1 Study of seismic diffractions caused by a fracture zone
2 at In Salah Carbon dioxide storage project

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4 **Abstract**

5 The In Salah CO_2 storage project in Algeria has injected over 3 million
6 tonnes of carbon dioxide into a water filled tight sand formation. Interfer-
7 ometric Synthetic Aperture Radar (InSAR) range change data revealed a
8 double lobbed pattern of deformation that has been modeled as the opening
9 of a sub-vertical fracture, or damage, zone. The location and geometry of
10 the linear feature were subsequently verified using a seismic reflection sur-
11 vey. The elastic properties of the fracture zone, including anisotropic Poisson
12 ratio (ν), Young's (E) and shear (G) moduli, were estimated from coupled
13 geomechanical and hydrological modeling of surface deformation and pres-
14 sure variations in the injection well. The elastic moduli reflect the fracture
15 properties after CO_2 flow through the fracture zone. Thus, the seismic sig-
16 nature of the fracture zone could be used for monitoring the CO_2 plume.
17 Using the estimated fracture model, we built two and three dimensional mod-
18 els consisting of an anisotropic fracture zone embedded within an isotropic
19 background. Finite-difference modeling of seismic shot gathers allows us to
20 estimate the effects of scattering from the fracture zone, potentially further
21 constraining the geomechanical model. From the seismic modeling results,
22 we find diffracted waves, induced by the fracture zone, which behave similar

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1 to point source diffractions. This modeling is intended to guide a search for
2 diffraction events in the 3D surface seismic field data. The modeling results
3 indicate that using the moduli estimated from geomechanical modeling, frac-
4 ture scattered events would be 100 times lower amplitude than the interface
5 reflections, and thus would be hard to detect. While diffracted waves are ob-
6 served in the field data, which may imply the need for revision of the fracture
7 model, including shape and elastic moduli, we are not able to match the field
8 observation with our modeled events. This work presents a frontier study
9 on the integration of geomechanical and geophysical methods at the In Salah
10 site as a means to test the estimate of the subsurface CO_2 flooded fracture
11 properties.

12 *Keywords:* geological CO_2 sequestration; In Salah project; finite difference;
13 seismic wave propagation; fracture

14 **1. Introduction and background**

15 Understanding and diagnosing the presence of high permeability fracture
16 or damage zones is an important component of carbon storage, especially for
17 industrial scale projects. The In Salah Gas project (a joint venture between
18 Sonatrach, BP, and StatoilHydro) located in the central region of Algeria
19 is one of the world's first industrial scale CO_2 storage projects and first to
20 be associated with a producing gas field (Fig. 1). Natural gas produced
21 from the Krechba field is high in CO_2 which is separated and injected into
22 the water leg of the field for geological storage. Over a period of about 8
23 years, 0.5 to 1.0 million tons of CO_2 per year had been injected into a 20m
24 thick, water-filled, carboniferous formation with a relatively low permeability.

1 Three wells with 1 to 1.5 km long horizontal sections, located at a depth of
2 approximately 2 km, serve as the injectors (Mathieson et al., 2009).

3 During the first five years of injection (2004-2007) ground deformation was
4 monitored using Interferometric Synthetic Aperture Radar (InSAR) range
5 changes obtained from the orbiting European Space Agencies C-band satel-
6 lites (Vasco et al., 2008). The range is the distance between points on the
7 surface of the Earth and a reference point, associated with the baseline posi-
8 tion of the satellite. The observations reveal changes of 5-10mm per year over
9 each of the injection wells (KB-501, KB-502, and KB-503 in Fig. 2a). Fig. 2a
10 shows 5 years of accumulated range change, where red color represents uplift
11 of the surface, which has been utilized to infer flow within both the reservoir
12 and a sub-vertical fault/fracture zone intersecting well KB-502 (Vasco et al.,
13 2010). In addition to InSAR measurements, 3D surface seismic data were
14 acquired over the same area in two surveys, the first in 1997 and the second
15 in 2009 (Gibson-Poole and Raikes, 2010). Fig. 2a shows the footprint of
16 surface seismic data coverage from 2009. The 3D seismic interpretation at
17 In Salah has mapped multiple horizons related to specific geological forma-
18 tions, with six of them labeled in Fig. 2b. Among those is the C10.2 the
19 reservoir interval into which the carbon dioxide was injected, and two shal-
20 lower horizons (C20.1 and C20.4) are the base and top of a 900m thick cap
21 rock. A recent study by using the InSAR and 3D seismic data sets shows
22 good spatial correlation between the ground surface uplift and subsurface
23 seismic attributes mapping, indicating the existence of a fracture zone which
24 possibly allows the upward flow of CO_2 (Zhang et al., 2015). Understanding
25 the properties of subsurface fracture zones, and the impact of CO_2 entering

1 those zones, is important for the In Salah project and, in general, for Carbon
2 Capture and Storage (CCS).

3 In this paper, we shall study the seismic diffraction response of a suspected
4 fracture zone using properties based on geomechanical modeling of well pres-
5 sure data and InSAR range changes, thus testing the ability of seismic data
6 to constrain the geomechanical model of a fracture zone derived from non-
7 seismic data. Because the fracture properties are estimated for a model of
8 CO_2 flooding the fracture zone, the seismic response indicates our ability to
9 monitor the CO_2 plume with time-lapse change in seismic diffraction. Such
10 diffraction wave response from a narrow fracture zone can be utilized to
11 image and characterize the fracture zone by diffraction imaging technique.
12 Diffraction imaging had been developed to detect small size subsurface ob-
13 jects (Landa et al., 1987; Kanasewich and Phadke, 1988; Tsingas et al.,
14 2011) based on coherent summation of diffracted events using an appropri-
15 ate traveltimes description in common-offset and common-midpoint domains.
16 Landa and Keydar (1998) use common-diffraction-point sections for imaging
17 of diffraction energy and detection of local heterogeneities. Berkovitch et al.
18 (2009) present a technique that is based on the multifocusing method. A
19 similar idea is proposed by Dell and Gajewski (2011), who use the common-
20 reflection surface operator. Several papers propose diffraction enhancement
21 by modifying pre-stack Kirchhoff depth migration using appropriate weight-
22 ing (Kozlov et al., 2004; Moser and Howard, 2008; Koren and Ravve, 2011).

23 A narrow zone in which the seismic reflections are pushed down, or de-
24 layed in time, is observed by comparing two time-lapse seismic datasets in
25 1997 and 2009 above the injection well KB-502 (Figure 3). The first sur-

1 vey in 1997 was used for hydrocarbon exploration and the recent survey in
2 2009 was conducted for CO_2 sequestration research. Although two seismic
3 surveys were not designed for time-lapse analysis and there is a systematic
4 discrepancy between them, we are able to see such a push-down after the
5 alignment (Zhang et al., 2013, 2014). The time delay of the push-down event
6 is approximately 13 ms, interpreted as the result of velocity changes induced
7 by injection of carbon dioxide, are shown in Fig. 3 for cross-line 1323. Zhang
8 et al. (2015) recently presented an integration study of seismic attributes and
9 InSAR datasets, which demonstrated the existence of the fracture zone. The
10 fracture zone was confirmed from the spatial correlation between the push-
11 down from the seismic reflection (indicated by two black dashed arrows in
12 Figs. 4a and b), a double-line feature from the positive curvature attribute
13 result (Figs. 4c and d), and surface uplift (Fig. 2a). The black solid line
14 represents horizontal portion of the injection well KB-502. The double-line
15 feature from the most positive curvature has been interpreted as the parallel
16 boundaries of the fracture zone. Thus, the width between the double lines
17 and their lengths leads to our estimations of the size of the fracture zone.

18 The above post-stack seismic image was derived from a multi-step work-
19 flow, including several techniques to suppress noise because the raw data are
20 noise contaminated. The possible diffraction wave generated from the frac-
21 ture zone would also be suppressed as noise. Thus, to study the diffraction
22 wave, we have to look at the pre-stack data. Fig 5 shows an unmigrated
23 common middle point gather located at the south side of the fracture zone.
24 Because the diffraction wave generated by the fracture zone acts similarly as
25 point source diffraction wave, it arrive earlier at far offset which is close to

1 the fracture zone and later at near offset, which is away from the fracture
2 zone. The blue dashed line highlights the reflection wave from interpreted
3 horizon C10.2. The event indicated by the pink dashed line has been inter-
4 preted as the diffraction wave. As expected, the fracture acted as a point
5 reflector at a depth a little shallower than the C10.2, and the diffraction wave
6 arrived earlier at far offset than near offset. The purpose of this study is to
7 reproduce the diffraction wave by seismic modeling method. In this way, we
8 can evaluate the possibility of monitoring the CO_2 flow through the fracture
9 zone.

10 Before presenting our modeling results, we first review evidence for the
11 damage zone in the inversion of the InSAR data by Vasco et al. (2008, 2010)
12 and the geomechanical modeling of Rutqvist (2012) and Rinaldi and Rutqvist
13 (2013). Next, we describe the exact elastic properties used for modeling, and
14 then present two- and three-dimensional finite difference seismic modeling
15 results.

16 **2. InSAR Interpretation and Geomechanical modeling**

17 Following the initiation of injection at InSalah, TeleRilevamento Europa
18 (TRE) and Lawrence Berkeley National Laboratory acquired, processed, and
19 analyzed satellite radar images from the European Space Agency's (ESA)
20 Envisat archive to evaluate InSAR's potential for monitoring the fate of the
21 injected carbon. Initially, range change associated with carbon dioxide in-
22 jection at well KB-501, located to the south of this study area, was used to
23 image a linear, high permeability zone within the reservoir that appeared to
24 correlate with an interpreted fault (Vasco et al., 2008). Vasco et al. (2010),

1 acting upon a suggestion that the double lobbed pattern resembled that of
2 a hydrofracture (Davis, 1983), interpreted the range change data associated
3 with the injection at KB-502 in terms of variable aperture change on a verti-
4 cal fault/fracture (damage) zone. In that study it was found that the InSAR
5 range change observations could be fit by a model in which the largest aper-
6 ture changes were concentrated around the injector. Because the reservoir
7 is situated in a low velocity zone within the model, it proved important to
8 accurately model the variations in elastic properties as a function of depth
9 (Vasco et al., 2010). In order to match two components of InSAR displace-
10 ment, quasi-eastwest and quasi-vertical, Rucci et al. (2013) required variable
11 aperture and volume change on sub-vertical damage zones intersecting all
12 three of the injectors. As in the earlier studies, the data could be satisfied
13 by changes concentrated around the injection interval.

14 Rutqvist et al. (2010), Rutqvist (2012) and Rinaldi and Rutqvist (2013)
15 incorporated coupled hydrological and geomechanical modeling to estimate
16 3D elastic properties of the fracture plane. Based upon the InSAR analysis,
17 the fracture zone was modeled as a narrow vertical zone. Fig. 6a shows the
18 entire geomechanical model and Fig. 6b shows a detailed view of the fracture.
19 The zone around the injection well (KB-502) is plotted as a white region
20 while the fracture zone is plotted as a purple rectangle. The geomechanical
21 modeling was used to estimate Young's moduli along the three axes (E_x , E_y
22 and E_z), and similarly the shear moduli (G_{xy} , G_{xz} and G_{yz}) and Poisson's
23 ratios (ν_{xy} , ν_{xz} and ν_{yz}) of the fracture zone (Table 1 is from Table 3 in Rinaldi
24 and Rutqvist, 2013). The success of the modeling of Rinaldi and Rutqvist
25 (2013) encouraged us to utilize the geomechanical parameters for seismic

1 waveform modeling. By using the same material properties for geomechanical
2 and seismic modeling, we can test the validity of the fracture properties with
independent measures (surface seismic and InSAR).

Table 1: Properties of fracture zone

Property	Value
Length	3500 m
Height	350 m
Total width	80 m
E_x	0.17 GPa
E_y	0.14 GPa
E_z	1.0 GPa
G_{xy}, G_{xz}, G_{yz}	1.0 GPa
ν_{xy}, ν_{xz}	0.18
ν_{yz}	0.25

3

4 **3. Isotropic and orthotropic elasticity**

5 Seismic wave propagation modelling is governed by constitutive relations
6 of linear elasticity. The particular stress-strain relationship is given by a
7 generalized Hooke's law which linearly relates the stress and strain through
8 the stiffness and/or compliance tensors (Nemat-Nasser and Hori, 1999). Eq.
9 1 shows classical stress (σ) and strain (ϵ) relationships in term of stiffness
10 tensor matrix ($\mathbf{C}$) and compliance matrix ($\mathbf{S}$), which also shows inverse re-
11 lationship between $\mathbf{C}$ and $\mathbf{S}$.

$$\begin{aligned}
\sigma &= \mathbf{C} \cdot \epsilon \\
\epsilon &= \mathbf{S} \cdot \sigma \\
\mathbf{C} &= \mathbf{S}^{-1}
\end{aligned}
\tag{1}$$

1 As in the geomechanical modeling of Rinaldi and Rutqvist (2013), we as-
 2 sume a layered isotropic background model. Thus, its stiffness tensor matrix
 3 $\mathbf{C}$ can be expressed in terms of P-wave velocity (V_p), S-wave velocity (V_s)
 4 and density (ρ) (Eq. 2). These parameters can be estimated from well-log
 5 measurements.

$$[C] = \begin{bmatrix} V_p^2 \rho & (V_p^2 - 2V_s^2) \rho & (V_p^2 - 2V_s^2) \rho & 0 & 0 & 0 \\ (V_p^2 - 2V_s^2) \rho & V_p^2 \rho & (V_p^2 - 2V_s^2) \rho & 0 & 0 & 0 \\ (V_p^2 - 2V_s^2) \rho & (V_p^2 - 2V_s^2) \rho & V_p^2 \rho & 0 & 0 & 0 \\ 0 & 0 & 0 & V_s^2 \rho & 0 & 0 \\ 0 & 0 & 0 & 0 & V_s^2 \rho & 0 \\ 0 & 0 & 0 & 0 & 0 & V_s^2 \rho \end{bmatrix} \quad (2)$$

6 Following the geomechanical modeling results, the fracture zone is repre-
 7 sented as an orthotropic elastic zone. Such orthotropic elastic media display
 8 symmetric anisotropic properties with 9 independent parameters. The frac-
 9 ture zone compliance matrix ($\mathbf{S}$) can be expressed in term of elastic moduli,
 10 Young's modulus (E), shear modulus (G) and Poisson's ratio (ν), as shown
 11 in Eq. 3.

$$[S] = \begin{bmatrix} 1/E_x & -\nu_{yx}/E_y & -\nu_{zx}/E_z & 0 & 0 & 0 \\ -\nu_{xy}/E_x & 1/E_y & -\nu_{zy}/E_z & 0 & 0 & 0 \\ -\nu_{xz}/E_x & -\nu_{yz}/E_y & 1/E_z & 0 & 0 & 0 \\ 0 & 0 & 0 & 1/G_{yz} & 0 & 0 \\ 0 & 0 & 0 & 0 & 1/G_{xz} & 0 \\ 0 & 0 & 0 & 0 & 0 & 1/G_{xy} \end{bmatrix} \quad (3)$$

1 Because of the symmetric elasticity, the compliance matrix has to be symmet-
 2 ric following Eq. 4. The stiffness matrix is then the inverse of the compliance
 3 matrix.

$$\begin{aligned} S_{12} = S_{21} &= \frac{\nu_{yx}}{E_y} = \frac{\nu_{xy}}{E_x} \\ S_{13} = S_{31} &= \frac{\nu_{zx}}{E_z} = \frac{\nu_{xz}}{E_x} \\ S_{23} = S_{32} &= \frac{\nu_{zy}}{E_z} = \frac{\nu_{yz}}{E_y} \end{aligned} \quad (4)$$

4 Thus, the 3D stress strain relationship for seismic wave propagation can be
 5 written as (Virieux, 1986b, Etgen, 1987, Daley et al., 2006):

$$\begin{bmatrix} \sigma_{xx} \\ \sigma_{yy} \\ \sigma_{zz} \\ \sigma_{yz} \\ \sigma_{xz} \\ \sigma_{xy} \end{bmatrix} = \begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ C_{21} & C_{22} & C_{23} & 0 & 0 & 0 \\ C_{31} & C_{32} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{66} \end{bmatrix} \times \begin{bmatrix} \epsilon_{xx} \\ \epsilon_{yy} \\ \epsilon_{zz} \\ 2\epsilon_{yz} \\ 2\epsilon_{xz} \\ 2\epsilon_{xy} \end{bmatrix}. \quad (5)$$

6 Our numerical implementation of seismic wave propagation is realized
 7 on a discrete grid using an explicit finite-difference technique, which was
 8 introduced by Madariaga (1976), Virieux and Madariaga (1982), Virieux
 9 (1986a). The inclusion of fractures follows the method of Coates and Schoen-
 10 berg (1995). A perfect match layer (PML) boundary condition is used to
 11 reduce undesirable edge effects (Roden and Gedney, 2000, Komatitsch and
 12 Martin, 2007, Martin et al., 2008a,b, Martin and Komatitsch, 2009). For
 13 3D calculations, an MPI (Snir et al., 1998) implemented is used to improve
 14 computational efficiency.

1 4. 2D Modeling

2 Our first attempt at seismic modeling is on a 2D subsurface model along
3 X-Z plane across the fracture zone. The 2D model is 5000 meters in width,
4 2000 meters in depth with $5 \times 5 \text{ m}^2$ size cell (Fig. 7). Two horizons have
5 been used in the construction of the 2D background isotropic model, which
6 represent two major seismic reflections (black arrows). The 2D elastic prop-
7 erties are constructed by interpolating and extrapolating available well-log
8 data (well KB-5) along these horizons (Fig. 2b). The well-log data, including
9 Gamma ray, Resistivity, V_p , V_s , density (ρ) and Poisson's ratio (ν), are shown
10 in Fig. 8. The V_p , V_s and density logs are used to calculate isotropic stiff-
11 ness tensor components C_{11} , C_{12} , C_{22} and C_{33} , following Eq. 2. Because the
12 fracture zone is nearly perpendicular to the model plane, it is placed in the
13 middle of the plane right above the C10.2 horizon (black dashed rectangles in
14 Fig. 7). As discussed previously, the orthotropic compliance tensor for the
15 fracture zone is calculated from moduli (E_x , E_z , G_{xz} and ν_{xz} in Table 1),
16 leading to the compliance matrix (S) in Eq. 6.

$$\begin{bmatrix} S \end{bmatrix} = \begin{bmatrix} 1/E_x & -\nu_{zx}/E_z & 0 \\ -\nu_{xz}/E_x & 1/E_z & 0 \\ 0 & 0 & 1/G_{xz} \end{bmatrix} = \begin{bmatrix} 5.88 & -1.06 & 0 \\ -1.06 & 1.0 & 0 \\ 0 & 0 & 1.0 \end{bmatrix} \quad (6)$$

1 Thus, the compliance matrix is inverted into the 2D stiffness tensor matrix
 2 ($\mathbf{C}$), as shown in Eq. 7.

$$\begin{bmatrix} C \end{bmatrix} = \begin{bmatrix} 0.21 & 0.22 & 0 \\ 0.22 & 1.24 & 0 \\ 0 & 0 & 1.0 \end{bmatrix} GPa \quad (7)$$

3 For the modeling, a wavelet with center frequency of 30 Hz is used as
 4 a vertical source placed 1km from the left boundary. Fig. 9 shows four
 5 snapshots of wavefields of the vertical component. The incidence wave first
 6 reaches the fracture zone at about 0.8 s and a diffracted wave is generated.
 7 From the wavefield of the diffracted wave, we find the fracture zone behaves
 8 like a point source rather than conventional reflection. The conventional
 9 reflection wavefields from horizons C30 and C10.2 are indicated by red dashed
 10 arrows (Figs. 9a and b). The diffracted wavefields caused by the fracture are
 11 highlighted with black dashed ellipse in Figs. 9b, and are indicated by black
 12 dashed arrows in Figs. 9c and d.

13 Seismograms has been generated for both horizontal and vertical compo-
 14 nents on the surface (Fig. 10). Figs. 10a, b and c show vertical component
 15 received seismograms for models with fracture embedded, without fracture
 16 and their difference. Figs. 10d, e and f show horizontal component received
 17 seismograms for models with fracture embedded, without fracture embedded
 18 and their difference. The figures are plotted with proportional amplitude for
 19 clear display. We observed the seismograms' horizontal components (Figs.
 20 10d and e) are about twice the amplitude of vertical component (Figs. 10a
 21 and b), and 10 times the amplitude of differences (Figs. 10c and f). Differ-

ences are caused by the fracture zone, and appear low amplitude compared with conventional reflection (yellow dashed arrows in Figs 10a and d). We also observe that the horizontal component diffraction is stronger than the vertical component. The black arrows point out boundary reflections, which have not been fully suppressed by PML. By comparing with post-stack seismic imaging and interpretation, we have identified two hyperbolic events as reflection from C30 and C10.2, which are pointed out by red dashed arrows in Figs. 10.

5. 3D Modeling

Following 2D modeling, we implemented 3D seismic modeling to look at azimuthal fracture response and to better compare with field data. The 3D model is 3000 meters in X and Y direction (within the blue dashed rectangle in Fig. 6b), 2000 meters in depth, and has $5 \times 5 \times 5 \text{ m}^3$ cell size. Fig. 11 shows the 3D isotropic model of V_p , which was constructed by interpolating well-log measurements (from well KB-5) along interpreted horizons. This V_p model is used to construct the model's isotropic stiffness tensors following Eq. 2. The fracture zone has been placed at the location obtained from geomechanical modeling. The compliance matrix of the fracture plane is also derived from geomechanical modeling results (elastic moduli in Table 1), following Eq. 3, and is shown in Eq. 8.

$$\begin{bmatrix} S \end{bmatrix} = \begin{bmatrix} 5.88 & -1.06 & -1.06 & 0 & 0 & 0 \\ -1.06 & 7.14 & -1.79 & 0 & 0 & 0 \\ -1.06 & -1.79 & 1.0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1.0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1.0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1.0 \end{bmatrix} \quad (8)$$

1 The stiffness tensors matrix is then derived by inverting the Eq. 8 into Eq.
2 9.

$$\begin{bmatrix} C \end{bmatrix} = \begin{bmatrix} 0.39 & 0.30 & 0.95 & 0 & 0 & 0 \\ 0.30 & 0.48 & 1.17 & 0 & 0 & 0 \\ 0.95 & 1.17 & 4.10 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1.0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1.0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1.0 \end{bmatrix} GPa \quad (9)$$

3 In preparation for future comparison with field data, the seismic modeling
4 results are generated according to the real field data acquisition geometry.
5 One shot gather geometry, crossing the fracture zone, is selected to test
6 our modeling. The acquisition geometry in map view is shown in Fig. 12.
7 The seismic source is located at the red point and receivers are at blue dots
8 which are sorted in 11 lines, as labeled in Fig. 12a. Double black lines in Fig.
9 12a highlight the boundary of the fracture zone. Fig. 12b shows wavefield
10 of vertical component at time 0.5s in a map view, where green points are
11 receivers's locations.

12 The vertical component of the modeled seismograms are shown in Fig.

13. Fig. 13a shows the shot gather with embedded fracture; Fig. 13b shows the shot gather without the fracture and Fig. 13c shows their difference. In Fig. 13a, the head wave is indicated by the white arrow; two major reflections are indicated by black arrows and the surface waves are indicated by yellow arrows. As expected, these seismic events arrive first at line 11 and last at line 1. The difference is calculated by subtracting Fig. 13a from Fig. 13b, and is assumed to be caused by the fracture zone. To clearly display the difference in Fig. 13c, its colorbar is scaled differently from Figs. 13a and b. Fig 13 shows that the fracture induced diffracted wave is about 1/100 of the conventional seismic events amplitude. We noticed that the first breaks of the diffraction wave in Fig. 13c arrive slightly earlier at line 1 and later at line 11. We also found strong amplitude variation at the first arrival of the diffraction wave (eg. red arrows in Fig. 13c). A different pattern of diffraction waves are indicated by orange arrows in Fig. 13c, which could be caused by the end of the fracture plane.

The vertical component shot gathers of line 11 in Fig. 13 are selected to compare the reflection and diffraction amplitudes. Two major reflections and the first arrival of the diffracted waves are indicated by yellow lines, labeled as 1, 2 and 3 in Fig. 14. The average peak amplitudes of these three events have been calculated, as $Avgamp_1=0.4949$, $Avgamp_2=0.3758$, $Avgamp_3=0.0033$ respectively. Trace No. 10 in Figs. 14a and b are overlain plotted in lower plot in Fig. 15, where the red seismogram is the modeled data with the embedded fracture and the black seismogram is without fracture. The upper two plots show enlarged views of the seismograms around the first and last arrival of the diffractions.

1 As stated previously, the shot gathers follow the real seismic acquisition
2 geometry in Fig. 12. We present a comparison between raw field data and
3 our modeling results in Fig. 16. It shows that the head waves (black arrows),
4 first reflection waves (yellow arrows) and surface waves (red arrows) fit well
5 between real and modeled datasets. Because the noise level is very high in
6 field shot gathers and the expected diffraction wave is weak, it is still difficult
7 to identify diffraction in the field data. However, we still can see some visible
8 relative flat events in the line 11 of Fig. 16a (indicated by the yellow dashed
9 ellipse), which is comparable to the diffraction wave events in Fig. 13c. This
10 is leading to our future work to identify these events as diffractions, separate
11 from reflections for characterizing the fracture zone.

12 6. Discussions

13 The coupled geomechanical modeling of Rinaldi and Rutqvist (2013) in-
14 cludes multiphase flow for supercritical CO_2 and brine, by using simulator
15 TOUGH-FLAC (Rutqvist and Tsang, 2002). These coupled models require
16 a large number of input parameters that might not be readily available, such
17 as parameters for geomechanical-hydrological interactions. In fact, the sim-
18 plified four-layer model were used for studying subsets of coupled processes.
19 However, such model could only generate three reflections, which is inappro-
20 priate to study the seismic response, especially compared to field data. Thus,
21 a detailed background model generated from sonic log is used in this paper
22 to determine the influence of a fracture zone on wave propagation.

23 Based on our modeling results, the diffraction amplitudes are very weak
24 compared to the reflection amplitudes, as expected. In our study on In Salah

1 fracture zone, the modeled amplitude of the diffraction wave, using static
2 moduli for the fracture zone derived from geomechanical modeling, is about
3 0.01 times of the primary reflection wave amplitudes. However, this result
4 is based on the current characterization of the fracture zone which includes
5 the estimated size, shape and static elastic properties.

6 In this paper, the 2D and 3D modeling results shown in Figs. 10 and
7 13 are presented as common shot gathers, which are different from the field
8 data common middle point gather in Fig. 5. As known, the common middle
9 point gather can be sorted from many shot gathers, each of which needs a
10 full 3D simulation. Further analysis of the 3D field data could investigate the
11 amplitude of diffractions for comparison to the geomechanical moduli model.

12 **7. Summary and Conclusions**

13 We have modeled seismic wave propagation to investigate the effects of
14 a fracture zone at the In Salah CO_2 storage site. The fracture properties
15 are based on geomechanical modeling which estimated the fracture geometry
16 and elastic properties. Our seismic modeling shows the geomechanical model
17 of a vertical fracture zone at In Salah can generate diffraction waves, which
18 are similar to a point source signature in the subsurface. The relative ampli-
19 tude of diffraction waves and reflection waves is shown to 1/100, indicating
20 that discrete scattered events from a fracture zone with the geomechanical
21 model properties would be quite weak and difficult to observe or image. It
22 is important to note that since the shape and static elastic properties of the
23 fracture zone comes from geomechanical modeling these parameters could
24 be revised by future interpretation of scattering in the seismic field data.

1 For example, a joint inversion of seismic and surface uplift datasets could be
2 used to improve the characterization of the fracture zone. Our results may
3 be considered as a static moduli limit for the expected elastic effects of the
4 fracture zone for an initial model of the fracture shape. This work represents
5 an effort to integrate seismic and geomechanical methodologies at this site,
6 allowing further constraints on fracture properties, and also providing input
7 to design of future monitoring surveys.

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15 was performed using the VISTA software package provided by GEDCO, now
16 a Schlumberger company, potentially allowing further constraints on fracture
17 properties, and also providing input to design of future monitoring surveys.

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Figure 1: (a) shows the location of In Salah project with Latitude (27.195) and Longitude (2.483333) highlighted; (b) shows the schematic workflow the CO_2 injection

Figure 2: (a) Surface deformation after 5-year CO_2 injection with seismic survey boundary polygon overlaid; (b) surface seismic image at cross-line 1295 (Gibson-Poole and Raikes, 2010).

Figure 3: Cross-line 1323 with injection well 502 inserted. A possible push-down event is located at horizontal portion of the injection well KB-502 (Gibson-Poole and Raikes, 2010).

Figure 4: (a) shows mapped surface at the bottom of the overlain shale, and (b) shows the zoomed view within the black dashed rectangle of (a). (c) shows the most positive curvature along the same surface, and (d) shows the zoomed view within the black dashed rectangle in (c).

Figure 5: A common mid-point gather, with mid-point close to the fracture zone. A potential diffraction event scattered from the zone is indicated.

Figure 6: (a) shows complete 3D geomechanical model; and (b) shows zoomed view of the model.

Figure 7: 2D elastic moduli model of stiffness tensors C_{11} and C_{12} are shown in the upper and lower figures. The black arrows on the left indicate the two major horizons of C30 and C10.2 as in Figure 2.

Figure 8: Well-log data at well KB-5, including Gamma ray, resistivity, V_p , V_s , density and poisson ratio.

Figure 9: Snapshots of wavefields of vertical component at (a) 0.7 s, (b) 0.8 s, (c) 0.9 s and (d) 1.0 s.

Figure 10: (a) and (d) show received vertical and horizontal seismograms with fracture embedded; (b) and (e) show vertical and horizontal seismograms without fracture zone; (c) and (f) show their differences.

Figure 11: (a) shows 3D V_p model with three plain view; (b) shows a slice of V_p in $X-Z$ plain; (c) shows a slice of V_p in $X-Y$ plain; (d) shows a slice of V_p in $Y-Z$ plain.

Figure 12: (a) shows acquisition geometry of a shot gather with source pointed in red and receiver locations highlighted in blue; (b) shows wavefield of vertical component at surface at 0.5s with receivers highlighted in green lines.

Figure 13: Received vertical component seismic data at surface: (a) with fracture embedded; (b) without fracture; (c) their difference. In the figure (a), white arrow indicates the head wave; black arrows indicate reflection events and yellow arrows indicate surface wave events. In the figure (c), red arrows indicate the first arrival of the diffraction wave and orange arrows indicate the diffraction wave from the end of the fracture zone.

Figure 14: Shot gathers of vertical component at line 11 in Fig. 13: (a) with fracture; (b) without fracture; (c) their difference. Two reflections are highlighted as 1 and 2. First arrival of diffraction is highlighted as 3.

Figure 15: Overlain display of trace No. 10 in Fig. 14a and b, where red seismogram is modeled with fracture embedded and black seismogram is without fracture embedded.

Figure 16: Comparison between real and modeled shot gathers: (a) real field raw shot gathers, and (b) modeled shot gathers from Fig. 13. Indicated on the figures are head waves (black arrows), first reflection waves (yellow arrows) and surface waves (red arrows).